GAS SEPARATOR SELECTION AND PERFORMANCE

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ABSTRACT
Many sucker rod lifted wells are operating at less than 30% electrical efficiency, because the downhole gas separator installed in the well is inefficient. Free gas interfering with liquid filling the pump is a major operational problem encountered in producing Sucker Rod Lifted wells. Gas interference is when free gas at the pump intake enters the pump filling displacement volume with gas in place of liquid, then significant loss in liquid production, reduced drawdown, increased failures and inefficiency occurs. Installing an incorrectly designed gas separator is the most common problem. Installing very long separators does not necessarily increase separator capacity or efficiency. Restrictions in the annulus above the pump intake such as tubing anchors result in reduced annular gas flow with gas preferentially entering the pump. A downhole gas separator has a maximum liquid throughput capacity. Casing size restricts the maximum size gas separator that can be installed in a well. The separator used in a well should be designed for the well configuration/conditions. Gas Separators with high separation efficiency should be used to effectively produce sucker rod lifted wells.

Introduction
Down hole gas separators when installed in a well should be both efficient plus effective, low cost and simple to install in the well, and perform without problems while installed. Hundreds of wells have been tested using power measurement equipment, dynamometers and acoustic liquid level instruments. Many of these wells were operating at less than 30% overall efficiency. Often, the main reason for inefficient operations is incomplete liquid fillage of the pump due to the downhole gas separator ineffective performance. Free gas interfering with liquid filling the pump is a major operational problem producing Sucker Rod Lifted wells. Gas interference is when free gas at the pump intake pressure enters the pump filling displacement volume with gas in place of liquid, then significant loss in liquid production and reduced drawdown occurs. Inefficient gas separators can be identified by obtaining an acoustic liquid level test indicating a high gaseous liquid column above the pump and the analysis of dynamometer data indicating a large portion of the fluids entering the pump is gas resulting in incomplete pump fillage. Periodic acoustic liquid level tests and dynamometer measurements should be performed to verify that the pump is filled with liquid and the downhole gas separator is operating properly. The discussion in this document is written to help increase the liquid capacity of downhole gas separators.

Separator Sizing
To correct inefficient downhole gas separation, the first option in a vertical well should be to set the pump below the fluid entry zone, if feasible. Setting the pump intake below the fluid entry zone is the most efficient method of downhole gas separation. If the pump cannot be set below the fluid entry zone, then a gas separator should be installed below the pump that offers an efficient gas/liquid separation chamber between the inside of the outer barrel of the gas separator and the outside of the dip tube in the separator. Each square inch of annulus area inside the outer barrel and outside the dip tube provides approximately 50 BPD of liquid separation capacity. 1/4 inch diameter gas bubbles flow upward in water at a rate of approximately 6 inches per second. Gas bubbles will be released from a liquid column if the downward liquid velocity is less than 6 inches per second. A liquid column having an area of 1 square inch travelling at 6 inches per second equals a flow rate of approximately 50 BPD. A simple method to determine the Down Hole Gas Separator Liquid Capacity is multiplying the square inches of annulus area inside the outer barrel and outside the dip tube by 50 BPD/Sq. In. Liquid Capacity of a separator is defined as the maximum rate of liquid that the separator can deliver to the pump intake with little or no gas entrained in the liquid.

The gas bubble rise velocity in a liquid depends upon the bubble size and other factors. As the gas bubble diameter increases from very small up to ¼ inch in diameter, then the gas bubble rise velocity increases to a bubble rise velocity of approximately 6 inches per second in water. From field data and lab data, the measured "average" gas bubble rise velocity at downhole pump conditions is accepted to be 6 inches per second for a gas bubble size approximately ¼ inch in diameter. The gas separator simulation[1] software will allow determination of "average" gas bubble rise velocity in a variety of gas separator configurations and sizes using actual field data.

More separator annulus area will result in greater gas separation capacity. The dip tube diameter should be large enough to have a pressure drop of less than 2 psi at a flow rate of 4 times the average pump production rate.

If the pump and gas separator are placed below the fluid entry zone, a gas separator outer barrel is not needed for gas separation. A tubing joint orange pealed on bottom, typically called a mud joint, should be used to protect the dip tube; when the dip tube is run in the well below the casing perforations.

Gas Separator

A common poor-boy gas separator assembly made from upset tubing is shown on the right side of Fig. 1. In Fig. 2, a higher capacity Collar-Size gas separator is shown.

Many gas separators are made from readily available oilfield materials that include thick wall tubing. The thick wall of conventional tubing reduces the area available for separating gas from liquid. A conventional, perforated-sub gas separator made from upset tubing reduces the internal area available for separating gas from liquid and greatly restricts the gas separator liquid capacity. To increase Gas Separator Liquid Capacity the outside diameter, OD, of the outer barrel of the gas separator should have the same diameter as the collar or larger to increase the cross sectional area and reduce the liquid downward velocity in the separation area. The perforated-sub gas separator is often called a poor-boy gas separator, where the tubing collars prevent the perforated sub laying against the casing wall. Liquid tends to accumulate along the casing wall and gas tends to collect in the center portion of the well bore, when the collars hold the perforated sub off the casing wall, then the tendency for the gas to enter the poor boy gas separator perforated sub when held off the casing wall by a tubing collar is greater.

The Collar-Size[2] gas separator, Fig. 2 has the outer barrel about the same size as the tubing collar OD, allowing the gas separator to rest against the casing wall if the separator is ran into the well with 3 or more tubing joints between the tubing anchor and the collar sized gas separator. Liquid tends to accumulate on the low side of the casing where the OD of separator touches the casing wall. This accumulated liquid will be more likely to enter the gas separator while the gas in the casing will tend to rise on the opposite wall (the high side of the casing wall). Thin wall outer barrel thickness and the OD of the collar sized gas separator equal to the tubing collar create increased cross sectional area and result in the capacity of the collar sized gas separator being greater than if the separator OD is smaller than the tubing collar and standard thickness tubing. Table 1 illustrates the separation liquid capacity of commonly available separator types.

Gas bubbles of ¼ inch diameter rise at a velocity of 6 inches per second in gas free water. The relative difference in density of the gas bubble compared to the liquid density is an additional factor impacting gas bubble rise velocity. The density of light oil is less than the density of water and the relative difference in the gas bubble density compared to the density of light oil is less than the relative density of the gas bubble compared to gas free water; because of this the gas bubble rise velocity in light oil will be less than 6 inched per second. More viscous oil will result in a slower bubble rise velocity and low viscosity oil will allow gas bubbles to rise at a faster rate. The industry uses an average of 6 inches per second for most gas separator capacity calculations, as has been discussed. The 6 inch per second velocity guideline applies to the downward liquid flow in the annulus area between the ID of the gas Separator and the OD dip tube. This gas bubble rise velocity is used to calculate the gas separator maximum liquid capacity. The Down-Hole Gas Separator Performance Simulation program[3] predicts how a separator will perform in the field so that the proper gas separator can be selected. A particular separator configuration can be analyzed to determine the gas separator capacity. The scaled animation of the gas bubbles moving with the liquids can be used to see how the gas separator separates the gas from the liquid during the pumping cycle. The gas bubble rise velocity can be changed and the simulation program can be used to determine what bubble rise velocity should be used in a particular installation as shown in the examples presented at the end of this paper.

Gas Velocity on Outside of Gas Separator

The problem of separating the gas from the liquid before the liquid enters the gas separator is also related to the mixing of the well fluids due to high gas velocity on the outside of the separator. Too high of gas velocity can create a gassy mixture that is difficult to separate. The gas velocity should be less than 10 ft per second in the annulus between the ID of the casing and OD of gas separator. The space between the outer barrel of the gas separator and the inside of the casing is an important consideration impacting downhole gas separation efficiency. Sufficient space should exist in the annulus so that the gas flow around the entry ports of the gas separator will not completely mix the free gas and liquid to create a mist composed of small liquid droplets carried by the gas; then the liquid cannot flow or fall into the gas separator annulus. If the outer barrel of the gas separator fits too closely into the casing I.D., excessive casing annulus gas velocity will prevent the liquid from entering and falling through the gas separator ports into the gas separator annulus. Also, sufficient room should exist around the outer barrel of the separator to allow an Overshot to be installed over the separator' if needed. A good separator design balances the required area surrounding the gas separator in the casing annulus and the area required in the gas separator annulus which determines gas separator liquid capacity.

Eliminate Poor Boy Gas Separator Deficiencies

A thin-wall outer barrel permits an increase in the gas separator liquid capacity. However, the problem exists of setting the gas separator down onto sand and collapsing the gas separator outer barrel. The collar-size gas separator with large ports and 1/8" wall has collapse strength approximately 75% of conventional tubing. The decrease in wall thickness increases the capacity of the gas separator substantially over conventional tubing wall thickness.

Large ports are used in the collar-size gas separator. The large ports allow liquid entry into the gas separator 100% of the time on both the upstroke and downstroke without pressure drop. The large ports allow liquid from the casing annulus to fall by gravity into the gas separator because the pressures inside and outside of the large ports are almost the same. The large ports result in more liquid flow and less gas flow from the casing annulus to the inside of the gas separator.

The gas separator capacity should exceed the pump capacity or inefficient performance will be obtained. If the calculated pump displacement exceeds gas separator liquid capacity, the pump rate should be reduced for better performance.

Gas Separator Length

Another factor to consider is the length of the gas separator. Many existing designs utilize from one to three pump volumes as the proper volume to contain in the gas separator between the inlet ports and the lower opening in the dip tube. Visual studies performed at the University of Texas lab having clear casing and a clear gas separator indicate that the rate at which gas bubbles migrate upwards in the liquid column and the pumping speed are two of the controlling factors. If a well is pumping 10 strokes per minute, the pumping cycle time is 6 seconds. Three seconds occur on the upstroke and three seconds occur on the downstroke. If gas bubbles are drawn down into the gas separator annulus during the upstroke, these gas bubbles should be liberated from inside the gas separator, when the pump is on the downstroke. On the downstroke, these bubbles will migrate upward at a rate of approximately 6 inches per second. If the downstroke time is 3 seconds, gas bubbles will migrate upward 18 inches. This suggests that a dip tube should extend at least 18 inches below the gas separator inlet perforations for a well pumping 10 strokes per minute. Longer length dip tubes results in additional friction loss and the release of free gas evolving from the oil flowing up the dip tube into the pump. A long stroke unit operating at 4 strokes per minute has a downstroke time of 7-1/2 seconds which will allow gas bubbles to flow upward approximately 45 inches suggesting a dip tube length of 45 inches. The collar-size gas separator has a dip tube that extends about 55 inches below the bottom of the outer barrel inlet ports which is sufficient to satisfy the great majority of pumping well conditions.

Collar Sized Gas Separator

The thin-wall, high liquid capacity, collar-size gas separator is sized to maximize the annular separation area inside the gas separator. The dip tube size, and wall thickness are chosen to minimize pressure drop and provide maximum flow areas. To have minimal pressure drop the area of intake ports into the gas separator is equal to area between dip tube and separator outer barrel; the large intake ports are distributed around the outer barrel to facilitate entry of liquid into the gas separator. The collar sized gas separator is a good balance between annular flow area, separator flow area, dip tube length and diameter and low pressure drop.

The collar-size gas separator is a complete unit; the top half-collar, the outer barrel and ports, dip tube, lower half-collar and bottom bull plug are all one assembly that functions together as a gas separator. The collar size gas separator[2] has the dip tube installed in the separator to insure the dip tube is of the proper size and length. It is not necessary to install a dip tube on the bottom of the pump as the correct size dip tube of the correct length is already permanently mounted inside the gas separator. Half-collar is located at the bottom of the separator with a bull plug attached to the bottom of the half-collar. If the well has a history of collecting debris and sand into the gas separator, a collection chamber (one or more tubing joints) should be installed immediately below the collar-size gas separator to collect the debris. Attach a chamber composed of tubing joints with bull plug on bottom of sufficient volume to hold the debris immediately below the separator.

Half-collar is located at the top of separator and should be attached to bottom of the tubing as a unit below the seating nipple. When casing size is adequate, a collar-size gas separator larger than the tubing size, can be run if additional liquid capacity is desired. For example, a 2-7/8 inch collar-size gas separator can be run using a cross-over immediately below a 2-3/8 inch seating nipple.

Gas Separator Throughput Liquid Capacity

Once a properly designed gas separator is installed in a well it is necessary to consider that its performance is affected by the completion design and the actual gas and liquid flowing conditions from the reservoir.

The throughput liquid capacity of the separator installation is defined as:

- The rate of liquid that the installed separator can deliver to the pump intake with a minimum of free gas.
- The throughput rate is limited by the rate of liquid that can enter through the separator ports into the separation chamber and by the downward velocity of liquid inside the separator.

The gas separator liquid capacity described in the previous sections and in Table 1 relates to the pump liquid rate that will not entrain gas bubbles to the bottom of the separator and into the pump intake, assuming that such liquid rate can be supplied by liquid flowing through the entry ports of the separator.

Although it seems obvious that the separator cannot deliver to the pump more liquid than what enters its separation chamber from the wellbore, this fact is often ignored by most operators. As described earlier in common separator designs, the entry of liquid into the separator is due to gravity flow similar to the flow of liquid over a weir. Therefore the entry ports have to be sized accordingly to allow free flow of liquid from the wellbore into the separation chamber. If liquid cannot enter the separator at the rate that the pump requires to fill the barrel during the plunger upstroke then the result will be incomplete pump liquid fillage. If the pump displacement rate is greater than the liquid throughput capacity of the separator as installed in the well the result will be that the separator will be “pumped off” and incomplete liquid pump fillage will persist. The presence of gas into the pump barrel is not due to poor gas/liquid separation capacity but is due to exceeding the liquid rate that can enter the separator.

Once the separator entry ports have been properly sized, the main factor that controls the rate at which liquid can enter the separator is the gas velocity in the annulus opposite the separator entry ports. As discussed earlier in detail, excessive annular gas velocity will carry the liquid past the entry ports and reduce the liquid input into the separation chamber. The velocity of the annular gas is controlled by the GLR (Gas Liquid Ratio) being produced, the casing/separator annular area and the in situ pressure. Full scale laboratory tests have shown that the throughput liquid capacity of a separator installation can be reduced significantly just by increasing the GLR of the flow into the wellbore while maintaining a constant pump liquid rate[5]. While at low-medium GLR the separation system operated efficiently (at its designed separation capacity) and no gas was delivered to the pump, when the gas flow rate was increased (higher GLR) the pump liquid fillage was reduced and eventually the separator was practically pumped off as the gas rate was continued to increase.

This effect was associated with a change in the annular flow pattern from “churn flow” to “annular flow” that is generally considered to occur when the in situ gas velocity exceeds about 10 ft/sec. Therefore as discussed in the next paragraph the casing size affects the performance of the separator installation especially in wells producing at high GLR.

The concept of throughput liquid capacity is also applicable to packer type separators that include a tail pipe since the GLR of the fluid discharged from the tail pipe into the annulus will control whether sufficient liquid will fall to the bottom of the separator and into the pump intake instead of being carried to the surface as a fine mist.

Gas Separator Liquid Throughput Capacity Limited by Casing Size

The maximum outside diameter of a gas separator that should be placed in a well is limited by the casing size of the well. The internal diameter of the casing is controlled by the weight per foot of the casing. When planning to drill a well and the well is expected to produce significant quantities of gas, then the maximum size OD of the gas separator that can be installed in a well is limited by the weight per foot/internal dimeter of the production casing planned for the well. 7 inch casing will allow a larger gas separator than 5.5 inch casing and 5.5 inch casing can contain a larger gas separator than 4.5 casing. Each casing size allows for installation a certain OD sized down hole gas separator, Table 2.

For maximum gas separator capacity, the OD of the collar-size gas separator should be approximately 80 % of the ID of the casing or smaller. Note that selection of a maximum capacity gas separator is relatively easy to determine, see Tables 1 and 2.

2-3/8 EUE tubing has a collar OD of 3.063 inches, 2-7/8 EUE tubing has a collar OD of 3.668 inches, 3-1/2 EUE tubing has a collar OD of 4.5 inches and 4 inch tubing has a collar OD of 5 inches. Collar-size gas separators of sizes 2-3/8, 2-7/8, 3-1/2, and 4 inch are available. Each of these separators has the outer barrel of the gas separator the same diameter as the OD of the collar. If a well is expected to be produced by sucker rod pump and the pump net displacement exceeds the separator capacity a large portion of the pump displacement will be lost to gas interference.

Example 1 –Proper Selection of Downhole Gas Separator with Sufficient Capacity

The Fig. 3 is an example of 10641 feet deep sucker rod lifted well that could not be efficiently operated; because the poor boy gas separator installed in the well had less capacity than the pump displacement. The fluid level acquired on the well showed an annular percent liquid of 57%, determined from the surface casing pressure buildup of 0.5 psi in 2 minute. The well was producing approximately 18 MscfD gas and very little liquid per day. The dynamometer test acquired on the well showed an effective plunger stroke with 34% of the 72 inch downhole stroke. The poor boy downhole gas separator in the well was failing to provide any gas separation benefit; because the 141 BPD pump displacement exceeds the 96 BPD poor boy gas separator capacity. After more than 6 months of poor inefficient operation of this well the installation was pulled. The casing size was 4.5 inches in diameter and a 2 3/8 collar sized gas separator was run into the well. Immediately the pump filled to 100% liquid with no free gas in the pump with a full pump production rate of 100 BPD. With the collar sized gas separator installed in the well the net pump displacement of 141 BPD is less than the 240+ BPD 2 3/8 inch collar sized gas separator capacity. The fluid level acquired after the collar sized gas separator was installed in the well showed an annular percent liquid of 22% determined from the casing pressure buildup rate of 1.8 psi per 1 minute. The annular gas production rate increased from 18 before to 161 MscfD after the installation of the sufficient capacity collar sized down hole gas separator. In this well the collar sized gas separator was efficient and effective, both the gas and liquid production rate increased. The high efficiency of the collar sized gas separator resulted in the pump filling up with liquid, with the well experiencing a significant increase in drawdown as producing bottom hole pressure was decreased by 600 psi.

Example 2 – Long Dip Tube is NOT Better

In this 10157 foot deep well the operator spent a significant sum installing a custom built poor boy gas separator, see Fig. 4 for the schematic. The 9 5/8 inch 47 lb weight per foot size casing has an internal diameter of 8.68 inches. Based on the casing ID a high capacity efficient gas separator could have been installed in the well. The poor boy gas separator design consisted of a 60 foot long 1 ¼ inch dip tube with a 6 foot 2 7/8 perforated sub. The annular area inside the gas separator between the perforated sub and the dip tube was less than 3 square inches resulting in a gas separation capacity of 147 BPD. The 306 inch long stroke pumping unit being operated at 3.9 strokes per minute had a 450 BPD pump displacement. Production from the well was 23 BOPD, 3 BWPD, and 110 MscfD. The poor boy gas separator was improperly designed for the very large pump rate. The liquid velocity between the OD of the dip tube and the ID of the outer barrel exceed the gas bubble rise and free gas almost completely filled the pump barrel with gas during the up stroke when the standing valve was opened to intake well fluids. The 60 foot long dip tube likely contributed to the poor boy gas separator failure because free gas evolves out of the oil as the oil flowed from the higher pressure at the dip tube intake into the lower pressure pump chamber at the top of the dip tube. The gas separator capacity compared to the pump displacement is important, the long 60 foot dip tube did not make the performance better, but likely contributed to the failure of this custom built poor boy gas separator.

Example 3: SPM Reduced to Improve Gas Separation Performance

The pumping speed can be adjusted using a variable speed drive on this horizontal well with the pump set at 7107 feet in the vertical section of the well above the kick off depth. Fig. 5 shows a pump card with incomplete pump fillage. The net pump displacement of 168 BPD at 6.82 strokes per minute, SPM, is less that the poor boy gas separator capacity of 210 BPD. The 210 BPD gas separator capacity is calculated using 6 inch per second gas bubble rise velocity. Since the down hole gas separator is failing and inefficient, then the gas bubble rise velocity was reduced to 4.6 inches per second until the calculated separator capacity 161 BPD is slightly less than the net pump displacement of 168 BPD. A slower gas bubble rise velocity less than 6 inch per second may be due to the lighter gradient of the mixture of oil and gas inside the separator or due to the design of the gas separator. Shown in Fig. 6 the SPM was reduced 6.14 SPM using the variable speed drive until the pump filled with liquid, resulting in the gas separator becoming effective. At 6.14 SPM the 140 BPD net pump displacement is less than the 161 BPD gas separator capacity using a 4.6 inch per second gas bubble rise velocity. The concept of slowing down the SPM to reduce the net pump displacement below the gas separator capacity has been successfully employed on other sucker rod lifted wells in many locations. In gassy rod pumped wells pumping faster often results in the down hole gas separator failing and the separator capacity being exceeded by the increased pump displacement. While reducing SPM to decrease the net pump displacement has been shown to improve down hole gas separator performance and increase the production rate from the well, because a slower SPM pump filled with liquid will produce more barrels of liquid per day than a fast SPM pump filled with primarily gas.

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Example 4: Measured System Gas Separator Efficiency

Gas Separator Efficiency is defined as the percentage of the free gas existing in the annulus at the pump intake pressure condition that is vented up the casing and produced from the annulus at the surface. A 100% efficient separation system implies that all the free gas present in the annulus at the pump intake depth is produced at the surface. This does not mean that gas will not be produced from the tubing since some of the gas will evolve from the oil as the fluid rises in the tubing and the pressure is reduced. The pump card allows the calculation of the free gas and the solution gas produced up the tubing and the acoustic fluid level analysis yields the free gas produced up the tubing/casing annulus. These values can be used to determine system gas separation efficiency[4]. Gas produced up the tubing is determined from the pump card detailed calculations using accurate dynamometer data acquired at the well. Free gas produced up the tubing/casing annulus is determined from the analysis of the acoustic fluid level test and casing pressure buildup rate acquired on the well. Total gas produced is the sum of the gas produced up the tubing plus the gas produced up the casing/tubing annulus. The system gas separation efficiency is determined by comparing the gas produced up the casing to the total of the gas produced from the well.

Fig. 7 displays the representative stroke and corresponding fluid level used to calculate the System Gas Separator Efficiency. The data selected was determined to be the most representative stroke for a well's normal operating conditions. The load on the pump card upstroke closely matches the calculated load reference line determined by the fluid level shot, meaning that the pump intake pressure is likely accurate for the purpose to determine the amount of free gas entering the pump. The bottom of the pump card is positioned on the zero load line, indicating that excessive friction is not present in the pump card loads and the tubing fluid gradient is representative.

Free gas and solution gas produced up the tubing from the pump card analysis is equal to 8.7 Mscf/D compared to 9.1 Mscf/D of gas flow up the annulus from the fluid level measurement. Thus a total of 17.8 Mscf/D of gas is produced from the well based on the pump card analysis and fluid level analysis. The calculated 17.8 Mscf/D compares reasonably well to the measured gas production rate of 22.0 Mscf/D. Analysis of the fluid level and dynamometer data yields total system gas separation efficiency of 51.2%

[equal to 100 X (9.1/17.8)] as shown in Table 3. The performance of this poor boy gas separator is inefficient or poor.

Example 5: Tubing Anchor Catcher above Pump Intake
Downhole gas separation can fail due to a tubing anchor catcher set above the pump. If a tubing anchor catcher (TAC) is run above the pump, the formation liquid can be held above the TAC by the gas flowing up the casing annulus and through the slips of the TAC to support gassy liquid above the TAC. The annular gas flow through the TAC plus the TAC creates a mechanism that does not allow the liquid to fall down to the separator intake where the liquid can be directed to the pump and pumped up the tubing to the surface. Often, the gas separator is considered to be very inefficient even though the gas separator is very efficient and is removing all of the liquid from the well that is present at the separator inlet below the TAC. Many gas separators are evaluated improperly because of this fluid behavior.

The liquid can accumulate as show in Figure 8. The well fluids behaved such that all of the liquid surrounding the separator inlet was being directed to the pump and the gas separator was very efficient. The separator and pump were removing all of the liquid from the area surrounding the separator inlet. Note in the picture that all liquid is being removed from around the separator liquid inlet.

A lot of liquid has accumulated above the TAC. This liquid is causing back pressure against the upper perforations and restricting fluid flow from the reservoir into the wellbore. Field measurements have shown that the pressure from liquid above the TAC can restrict production from the reservoir more than 80% so that very small amounts of liquid are obtained from the well.

A gaseous liquid column depression test should be performed to determine if the condition shown in the picture exists in the well. Fig. 9 shows the fluid level depression test data. The casing valve is closed, which causes the casing pressure to increase as shown. The increase in casing pressure depresses the gaseous liquid column down to and below the TAC. Notice that the gaseous liquid column is depressed down to the TAC, then a gaseous liquid column does not exist below the TAC. The separator is working correctly since all of the liquid below the TAC is being pumped from the casing annulus.

When fluid level measurements show this condition exists, replacing or changing the gas separator will not increase the production. In the condition above, the gas separator is working fine.

Most operators have said that a gas separator was not operating efficiently when a high fluid level exists and low pump fillage occurs. The above pressure test should be performed. The operator really does not know that liquid collecting above the TAC is restricting production from the well and is not the result of an inefficient gas separator. The operator tries to get a better gas separator when the gas separator is not the problem and a better separator will not help. All operators should perform the above test when suspecting an inefficient gas separator is causing a high gaseous column in the annulus..

Operators may have a tubing anchor liquid collection problem and not even working on the actual problem. A major company had 11 wells with poor pump fillage that was considered to be caused by a gas separator problem while in reality 4 of the 11 wells had a tubing anchor liquid hold-up problem and not a gas separator problem. The problem is common. The tubing anchor with the gaseous fluid column combine to create a choke mechanism that regulates gas flowing up the casing annulus.

Recommendations
In a vertical well when a rat hole or dead space below the bottom of the perforations exists, then a recommended practice is to use the natural gas separator by setting the pump intake below the perforations. It is recommended toclean out the debris below bottom of the perforations and to tag for fill to determine if well conditions are unfavorable for placing the pump intake in the rat hole. When the separator is above the producing zone, the diameter of the outer barrel of the gas separator should not be larger than about 80% of the casing internal diameter in high producing gas rate wells. The gas separator liquid capacity should always exceed the pump capacity. Use the Echometer Gas Separator Simulator Software Program to determine gas separator liquid capacity. Use dynamometer and fluid level analysis to determine pump fillage and separator system efficiency. Determining gas separator efficiency from pump fillage when using high slippage pumps can be very misleading since the separator may be separating very little liquid from gas and the actual liquid production rate may be very low.

The bottom of the dip tube should extend below the bottom of the gas separator inlet ports. The minimum length of the dip tube is calculated by the gas separator simulator software and an approximately length can be estimated by the ratio of 200/SPM inches. A long dip tube can be detrimental. A 5.5 foot dip tube length is usually sufficient for efficient gas separation for gravity-driven separators. The dip tube should extend about 4-5 feet below the separator inlet openings.

Maximize the size of the separator annular area to maximize the separator liquid capacity. Using a mud anchor with thin walls increases the size of the separator annular area. But efforts should be made to ensure that the mud anchor walls have the necessary strength. For gravity-driven separators in low viscosity fluid applications, good gas-liquid separation occurs when the superficial downward liquid velocity inside the separator is 6 in/second or less. Excessive gas velocity in the casing annulus reduces the separator performance since it prevents liquid from entering the separator openings. The annular area between the casing ID and the separator OD should be large enough so that gas velocity in the casing annulus is less than 10 ft/sec. The inner diameter of the dip tube should be sufficient to minimize the overall pressure drop through the separator.

Under laboratory conditions, increasing the total area of the openings into the separator to over 65% of the separator outer barrel-dip tube annular area does not considerably improve the separator efficiency. Multiple rows of opening are not necessary. Additional rows should only be considered if port plugging is anticipated.

Conclusion

Casing size determines the maximum size gas separator than can be installed in a well so that annular gas flow will not reduce the liquid throughput efficiency by restricting liquid inflow into the separator chamber. A specific design and size of a gas separator determines the maximum liquid rate that will not entrain gas into the pump intake. This rate is defined as the Separator Liquid Capacity. If the pump displacement exceeds the separator liquid capacity, then gas separation will fail and the producing efficiency of the well will be poor. Proper gas separator selection requires that pump displacement not exceed gas separator liquid capacity.

References

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Nomenclature:

OD = Outside Diameter
ID = Inside Diameter
TAC = Tubing Anchor Catcher

Table 1 – Liquid Separation Capacity for common separators

Type	*Size inches*	*Separation Liquid Capacity, BPD*
Gas Separators for 4-1/2 inch Casing		
Natural Gas Separator	2 3/8	420
Collar Size Gas Separator	2 3/8	275
Poor Boy Separator	2 3/8	96
Gas Separators for 5-1/2 inch Casing		
Natural Gas Separator	2 7/8	580
Collar Size Gas Separator	2 7/8	443
Heavy Wall Gas Separator	2 7/8	372
Packer Type Separator	2 7/8	444
Poor Boy Separator	2 7/8	190
Gas Separators for 7 inch Casing		
Natural Gas Separator	2 7/8	1200
Collar Size Gas Separator	4 1/2	1044
Collar Size Gas Separator	4	833
Collar Size Gas Separator	3 1/2	644
Collar Size Gas Separator	2 7/8	443
Heavy Wall Gas Separator	2 7/8	372
Packer Type Separator	2 7/8	1089
Poor Boy Separator	2 7/8	190

Gas Bubble Rise versus Downward Liquid Velocity

Table.2 Casing Size Limits Maximum Liquid Production Rate Due to Gas Separator Capacity

Casing Size Inch	Max Separator Size Inch	Tubing Collar OD Inch	Separator Barrel OD Inch	Separator Capacity BPD
4.5	2 3/8	3.063	3.063	275
5.5	2 7/8	3.668	3.668	445
7.0	3 1/2	4.500	4.500	644
7.0	4	5.000	5.000	833
7.0	4 1/2	5.560	5.500	1044

4.5 13.5# Casing ID 3.92 inch
5.5 17# Casing ID 4.89 inch
7.0 26# Casing ID 6.276 inch

Table.3 Measured System Gas Separator Efficiency

Gas	
Dissolved Gas in Oil	2377.7 scf
Total Gas Up Tubing	8.7 Mscf/D
Annular Gas from LL	9.1 Mscf/D
(Calc) Surface Gas at Standard Conditions	17.8 Mscf/D
(Input) Surface Gas at Standard Conditions	22.0 Mscf/D
System Gas Separation Efficiency	51.2 %

Figure 1 – "Poor-Boy" Gas Separator

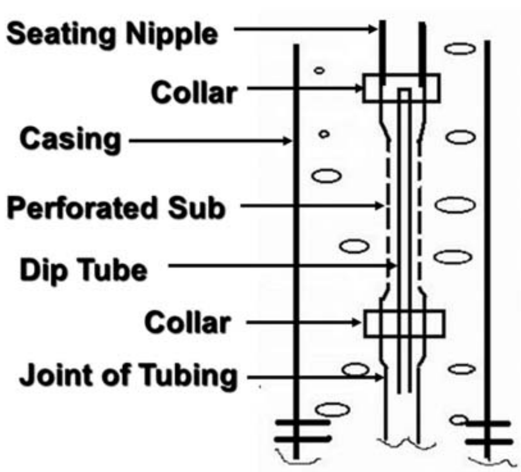

Figure 2 – Collar Sized Gas Separator

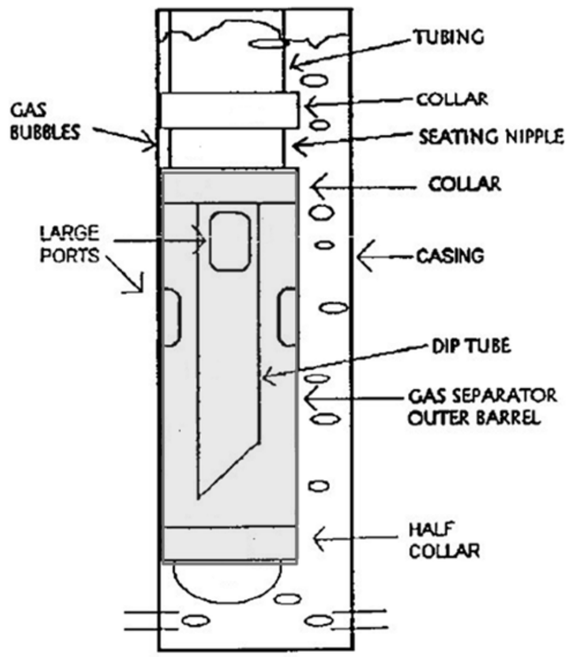

Figure 3 – Example of Gas Separator Selection with Sufficient Capacity

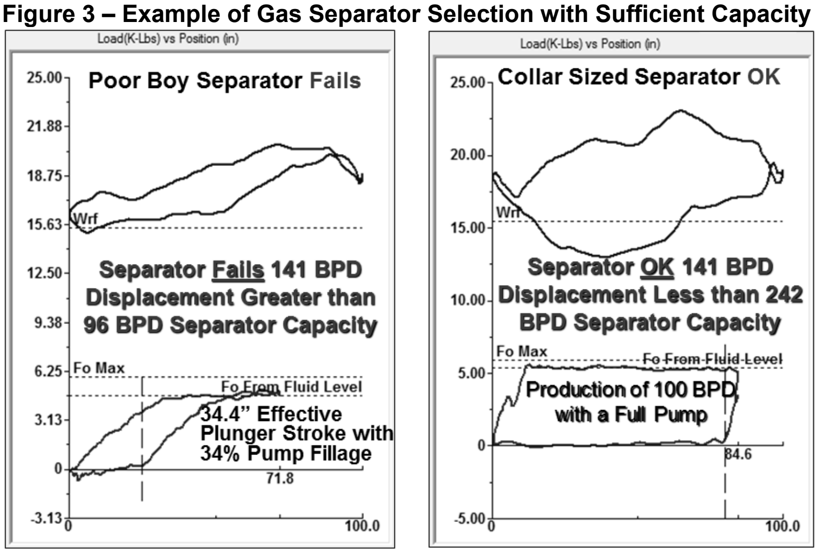

Figure 4 – Poor Boy Down Hole Gas Separator with 60 Foot Dip Tube

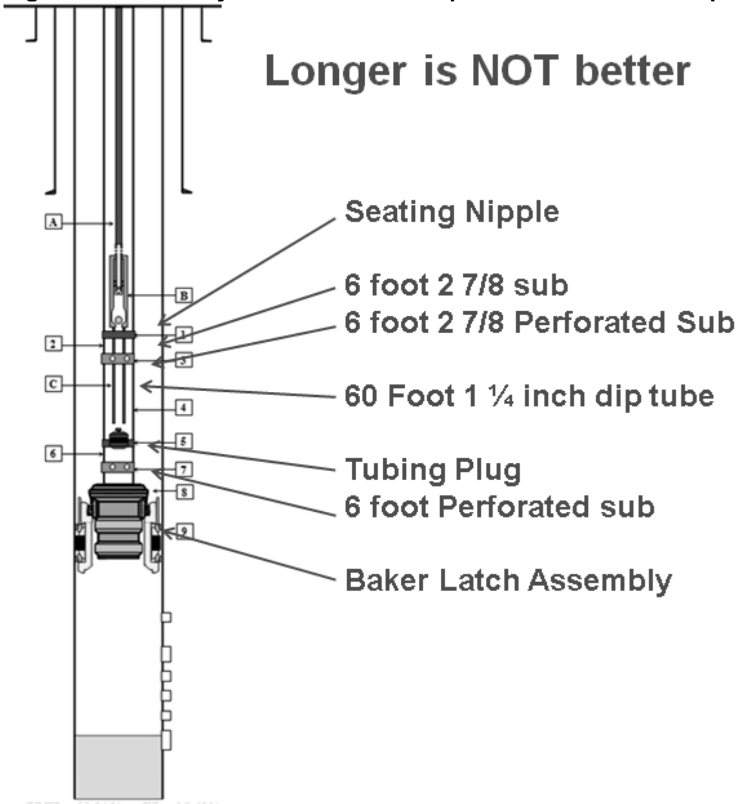

Figure 5 – Example 3 – Adjust Gas Bubble Rise Velocity to Match Pump Displacement

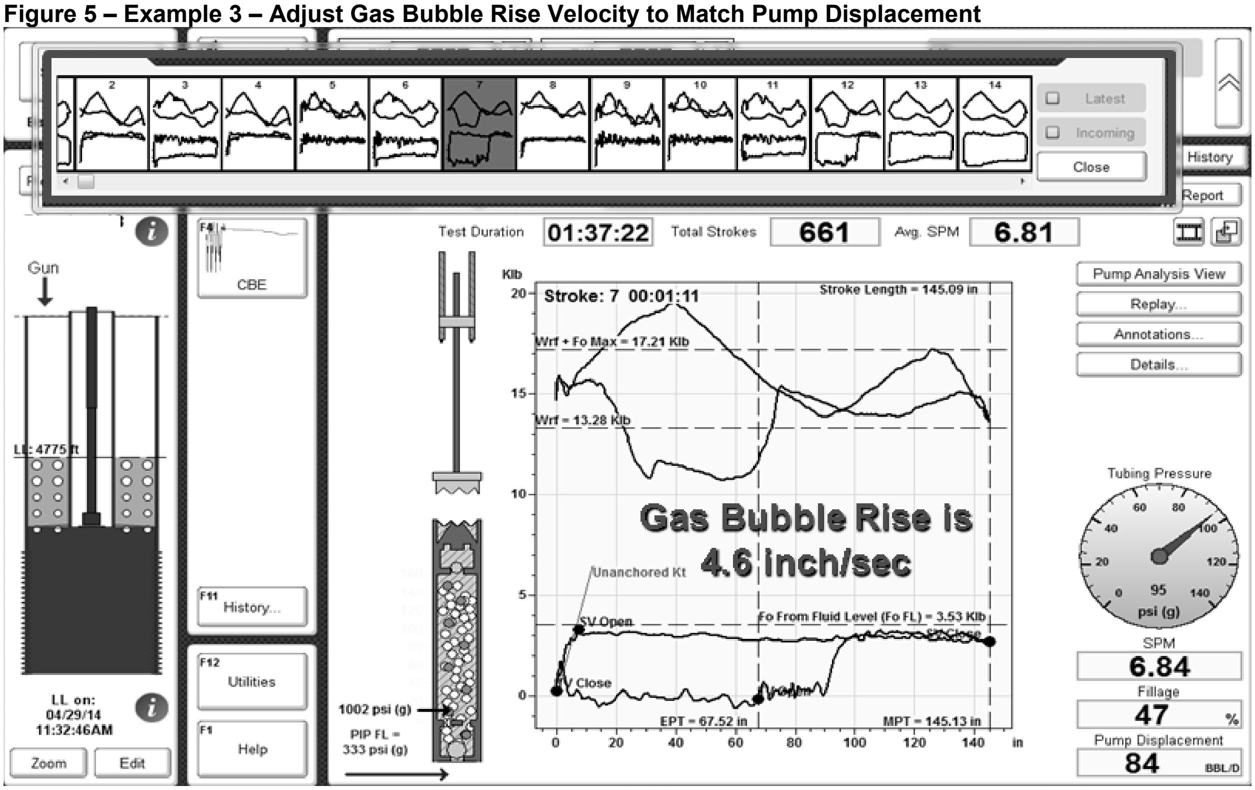

Figure 6 – Example 3: Reduced SPM using VSD so Pump Displacement Less than Separator Capacity

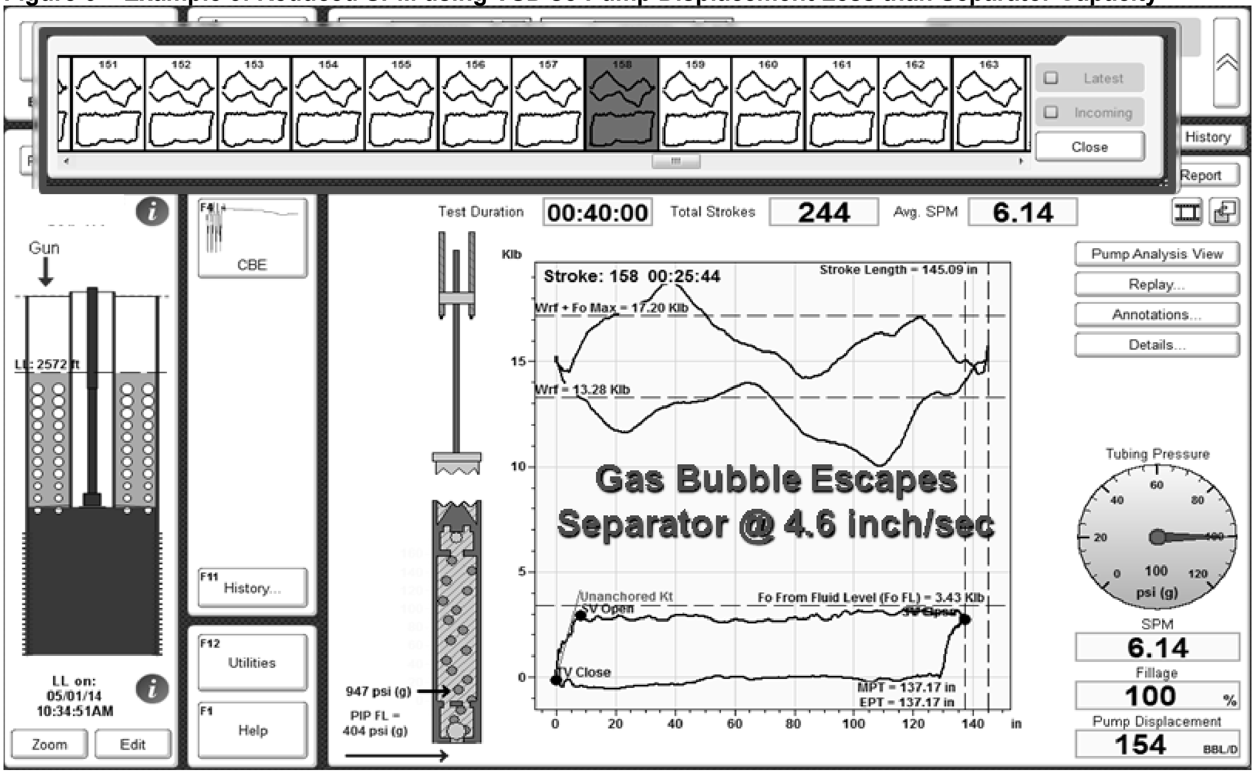

Figure 7 – Example 4: Well's System Gas Separation Efficiency is 51.2% Equal to 9.1/17.8 MscfD

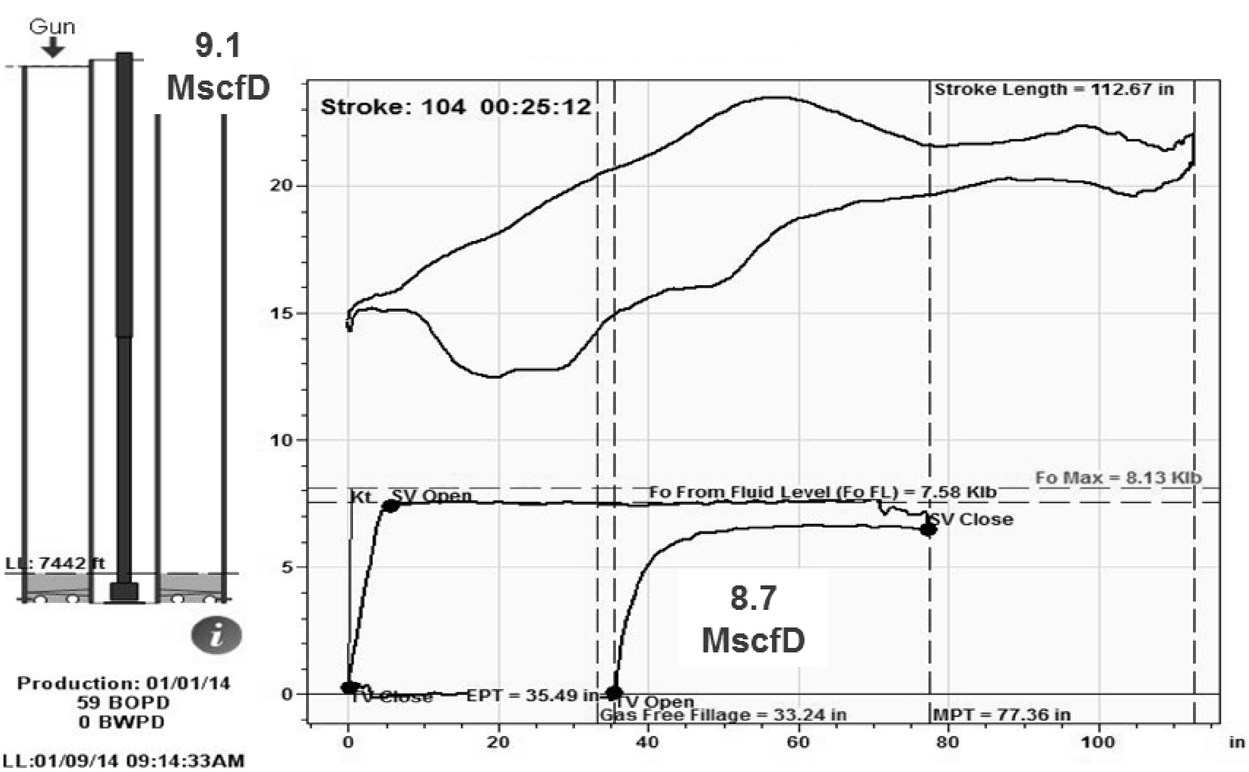

Figure 8 – Schematic of wellbore fluid distribution with TAC set above pump

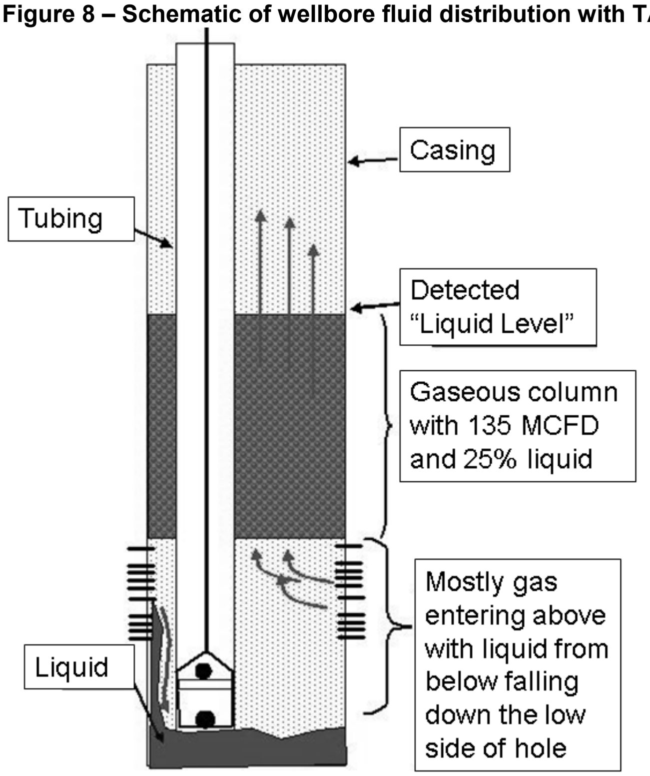

Figure 9 – Summary of Liquid Level Depression Test